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EnergyAustralia®

29 September 2010

Mr John Pierce
Chairman
Australia Energy Market Commission
Level 5, 201 Elizabeth Street,
SYDNEY NSW 2000

Dear Mr. Pierce,

AEMC Transmission Frameworks Review – Issues Paper

EnergyAustralia welcomes the opportunity to respond to the Australian Energy Market Commission (AEMC) Issues Paper commencing a Transmission Framework Review ('the Review'). The terms of reference from the MCE specify that the Review is to focus on identifying any inefficiencies or weaknesses in transmission and generation investment and operational decisions, particularly in light of the anticipated impacts of climate change polices.

We observe that some key aspects of the frameworks governing transmission investment have only been in place since late 2006 following considerable review by the Commission and stakeholders and there are significant rule changes that are currently in progress or have recently come into place (such as the creation of the role of National Transmission Planner and the new Regulatory Investment Test for Transmission (RIT-T)).

We are not aware of any evidence that would suggest that the existing frameworks do not promote efficient outcomes consistent with the national electricity objective (NEO). However, there have been a number of recent changes to the frameworks that will have large impacts on the planning of the transmission network, so it is too early to determine what the impact of these changes will be and what further changes will be needed. We therefore do not support another wide ranging review of the economic framework for transmission investment at this time. This would only serve to undo the basis of the previous framework review – that is to create an environment of investment certainty for all stakeholders.

While at this stage we do not believe there is any need for an overhaul of frameworks, there would be benefit in reviewing the rules architecture to ensure it delivers consistent and expected outcomes. A fuller and clearer picture of the current statutory framework could be an important basis for identifying issues for reform and change. We see benefit particularly in a considered review of the operation of the Rules in terms of service definition and charges to customers. Recent reviews (SENE) and Rule changes (United Energy Rule change on TUoS recovery) suggest there is some ambiguity in how the Rules operate in respect of the interaction of assets and services delivered by TNSPs and the process for passing through the costs of these assets and services to customers.

The proposed Transmission Framework review focuses on the interaction of generation with electricity transmission with little or no reference to other important contributors such as customers or distributors (DNSPs). The issues paper appears to disregard the role of DNSPs as the network services providers between transmission networks and load. We are concerned that decisions made in transmission do to a large degree pre-empt the approach taken in distribution. EnergyAustralia strongly submits that the Commission's consideration in this Review must extend to the impacts for distribution as it is not satisfactory for changes to DNSP frameworks to be consequentially adopted following a transmission only review.

The AEMC Issues Paper proposes that a "Negotiated Service" framework might apply where a NEM participant requires service above the standard levels provided. We have struggled with this concept in both a transmission and a distribution context as carving out different service levels from networks that convey electricity to multiple customers is often at odds with the physical capabilities of the network. In our submission we argue that establishing a complex system of negotiated access rights between generator and TNSP is neither practical nor warranted. While there may be benefits in reviewing the allocation arrangements between generators and loads, the current type and range of regulatory incentives on NSPs have been demonstrated to provide appropriate NSP behaviours without exposing them to market risk.

We also suggest that

1. Information and price signals can provide financial incentives for generators and load to make efficient location decisions by trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source; and
2. There is an opportunity to improve outcomes for customers by improving pricing arrangements from transmission to distribution to retailer.

In our submission we provide responses to the questions posed by the AEMC. We have also provided further commentary on the 4 key areas that are outlined above namely;

- Timing, focus and scope of the Review,
- Negotiated network services,
- Locational price signals, and
- Transparency and advance notice of TNSP pricing.

Should you have any questions in relation to this submission please contact Ms Jane Smith on 02 9269 4171.

Yours sincerely

CRAIG MOODY
A/Executive General Manager
System Planning & Regulation

EnergyAustralia®

Transmission Framework Review – Response to Issues paper

September 2010

Transmission Framework Review – Response to Issues Paper

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1 General comments

1.1 Timing, focus and scope of the review of the transmission framework

1.1.1 Timing of the Review

Whilst the NEM may face a period of significant change as a result of substantial new generation investment, it should also be noted that there has already been significant change in transmission frameworks in the last 15 years, driven more by economic and structural reform agendas.

In particular, there have been significant reforms since the 2005 NEL amendments. These changes include the review and effective replacement of the economic regulatory and pricing frameworks in Chapter 6 and the new Chapter 6A. In addition the frameworks for network planning of both transmission and distribution in Chapter 5 have been reviewed and changes in relation to transmission have been implemented. The MCE response to review of distribution planning is awaited. AEMO have also had a continuing work programme of reviewing and revising market systems and metrology in Chapter 7 including the significant harmonisation of metrology requirements in 2007.

We therefore question whether another wide ranging fundamental review of the transmission framework is necessary, given that changes based on previous reviews have only been in place since late 2006 or later. There are significant rule changes that are currently in progress or have only recently come into place such as the National Transmission Panel (NTP) and Regulatory Investment Test for Transmission (RIT-T) that will have significant impacts of the planning of the transmission network. It is too early at this stage to determine what the impact of these changes will be and what further changes will be needed.

1.1.2 Focus of the Review

The proposed Transmission Framework review focuses on the interaction of generation with electricity transmission with little or no reference to other important contributors such as customers or distributors (DNSPs). The issues paper appears to disregard the role of DNSPs as the network services providers between transmission networks and load. As a general example of this is the statement in the executive summary that “the Commission intends to propose a long term vision for the appropriate role of transmission in providing services to the competitive sectors of the market, including both generation and load customers”. Assuming the reference to load customers is broader than customers connected directly to the transmission network, the omission of DNPSs in this vision neglects to consider:

- the role of DNSPs as the immediate recipient of TNSP services,
- that the DNSPs are responsible for payment of transmission related charges and in particular the role of DNSPs in passing through transmission related charges to load customers, and
- that to the extent that changing generation profiles are likely to affect transmission networks, they are likely to affect distribution networks as well.

A more specific example is the omission of any reference to the joint network planning which occurs between TNSPs and DNSPs and the importance of this planning for ensuring that TNSP response to load or other network incentives are in fact delivered. Efficient joint planning can result considerable efficiencies in network investment. The integration of replacement and capacity planning is particularly important in this regard. It should be noted that a number of joint planning models exist, and operate with different levels of effectiveness. This review does not consider that there may be an issue in this regard.

Another important issue is the extent to which any changes or even fine tuning to existing transmission frameworks may, or should, impact DNSPs frameworks. To the extent that any consequential changes might need to be made the DNSP frameworks the potential consequences should be considered as part of this review.

The Commission acknowledges[1] that the transmission frameworks are complex and inter-related and that it will be necessary to develop internally consistent packages of reforms.

However, past experience has shown that decisions made in transmission do to a large degree pre-empt the approach taken in distribution. The proposed application of the SENE concept to distribution provides an example of this as does the application of the negotiated service framework in Chapter 6. EnergyAustralia strongly submits that the Commission’s consideration must extend to the impacts for distribution as it is not

[1] August 2010 AEMC Issues Paper Transmission Frameworks Review, p iv

satisfactory for changes to DNSP frameworks to be consequentially adopted following a transmission only review.

1.1.3 Scope of the Review

Whilst we question whether a wider ranging fundamental review is necessary, we believe there would be benefit in understanding the starting position of any transmission reform agenda which would involve a more detailed look at the architecture of the existing rules and how the existing rules actually operate. In many instances terminology has been either duplicated or not referenced altogether which is a symptom of multiple waves of reform of the transmission framework.

A fuller and clearer picture of the current statutory framework could be an important basis for identifying issues for reform and change.

1.2 Negotiated network services

The AEMC paper proposes that a “Negotiated Service” framework might apply where a NEM participant requires service above the standard levels provided. We have struggled with this concept in both a transmission and a distribution context as carving out different service levels from networks that convey electricity to multiple customers is often at odds with the physical capabilities of the network.

This concept has most recently been advocated by the AEMC in relation to the construction of SENE assets, which would connect multiple generators at a remote location, but not be considered part of the shared network. SENE assets are shared generator connection assets and a form of generator pricing for their use has been proposed.

However the use of the “Negotiated Service” framework for shared network <u>augmentation</u> with multiple participants is problematic:

- Generators are direct competitors in the NEM and a transmission configuration with adequate capacity for both would be unlikely to satisfy the strategic interests of either;
- Generators would only make a joint application or participate in joint negotiations if it suited their business interests to do so; and
- In the very unlikely event that one generator did place a significantly high value on gaining access to the market to request the augmentation; the asset would naturally benefit both generators. As a shared element of the transmission network, it would reduce transmission loss factors and provide unrestricted market access to both. Indeed, altered flows through the assets would accompany a variation in load or generation at every connection point to the meshed transmission network.

The issue that EnergyAustralia raised in response to the SENE consultation is the complexity that would be created by such an arrangement where multiple participants negotiate different access arrangements to shared infrastructure. This complexity would be even greater in a meshed network. The electrical flows in each element of the network follow Kirchhoff’s Law, rather than accounting or economic principles. As a consequence, in a meshed network it is physically impossible to identify which component of flow is associated with the activities of a particular participant. The manifold constraints (in both normal and contingency conditions) that can occur on a meshed network are the result of the combined activities of participants at many locations as well as the actions of the NSP and the inherent characteristics of the network.

<u>A Negotiated Access Rights framework?</u>

The concept of a financial access rights market has been contemplated (and dismissed) on a number of occasions since before the commencement of the NEM, and has been raised again in the AEMC’s consultation paper on SENE assets.

A system of financial access rights would require a secondary financial settlement to the NEM, in which the available capacity at connections to the network would be traded and in which the market values and quantities of delivered energy would form an input. Potentially, the NSP would be a counter party to such trading, in that maintenance and operational requirements affect the network capacity. This would expose the NSP to market trading outcomes in a way which is not contemplated in the current regulatory framework. Current TNSP performance incentives focus on equipment availability and do not impose market levels of risk. We question whether exposing TNSPs to market risk is in the long term interest of customers.

EnergyAustralia does not believe that a complex system of negotiated access rights is warranted, and that the current type and range of regulatory incentives on NSPs have been demonstrated to provide appropriate NSP behaviours without exposing them to market risk.

1.3 Locational price signals

The current pricing arrangements for prescribed transmission assets do not permit the cost of shared asset infrastructure to be recovered from generators. Those costs can be material. As there are currently limited location-specific charges for generators, it has the potential to affect a generator's siting decision. It would seem to make sense for generators to respond to signals which factor in the network cost for conveying electricity to load in the same way as the cost of fuel transport or haulage and other siting costs.

Under a central planning regime, the long run marginal cost of generation and transmission was integrated into a wholesale price. However since the onset of vertical separation and the establishment of the National Electricity Market in the mid 1990's, generation businesses were separated from the transmission network. This means that generator prices do not include any cost of the shared transmission network and almost all of the costs of transmission are directly allocated to load customers. For incumbent generators these costs are not factored into investment or operational decisions. For new generators, only the additional cost of connection to the shared network needs to be factored in their decision of where to invest/locate.

The AEMC may wish to consider the solid arguments in favour of providing transmission price signals to both new and incumbent generation;

- The absence of locational price signals for existing generators means new generators must in effect compete with the 'raw' cost of generation, without transmission network costs. Providing a transmission price signal to incumbent generation would create a level playing field and stimulate incentives for generator location in the right areas.
- Whilst new generators pay for dedicated connection costs to the transmission network, information and price signals should also provide financial incentives for new generators (and loads) to make efficient location decisions by also trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source.

The absence of sufficient transmission price signals for all generators creates the need to create second best pricing signals to encourage appropriate locational investment. The existing avoided TUoS arrangements are unstable, particularly in an area where the embedded generation and load are closely matched. Moreover, being based upon the transmission price structure, which varies markedly by region, they are not cost reflective.

Market price signals should also encourage generators to invest in the appropriate fuel type (for example wind-powered or gas-fired plant) and technology (such as baseload or fast-start plant). We would caution however that Rules should not favour one choice of fuel type over another, except on economic considerations. Prioritisation of fuel types is a role for government to decide through market signals or otherwise and should not be the role of NEM policy makers or TNSPs.

1.4 Transparency and advance notice of TNSP pricing

As a DNSP, EnergyAustralia has the important role in setting network use of system charges to be passed on to customers. The charges we pass through include the prices required to recover our own costs of providing standard control services as well as the pass through of transmission charges (and other pass through charges).

Our obligations in establishing prices for customers can be challenging. On one hand there is increasing demand from the Regulator and end-customers for greater transparency and certainty in price setting between years. On the other hand we are subject to the pricing processes and methodologies determined by the coordinating TNSP for the transmission component which we have little control over.

Chapter 6A of the Rules provides the framework for TNSPs to recover the costs of providing transmission assets through levying charges on participants. It regulates the prices that may be charged by TNSPs for the provision of prescribed transmission services and sets the basis for the charging of negotiated transmission services. For prescribed transmission services, a TNSP must charge in compliance with its published pricing methodology, which is approved by the AER for the duration of the regulatory control period.

But whilst a TNSP must charge in compliance with its published pricing methodology, as recent experience has shown the TNSP can modify the pricing methodology with effect during a regulatory period. Recent experience in NSW has shown that the consequent impact of a modified pricing methodology can mean significant changes to the pricing structure for prescribed transmission services. This in turn translated into significant transmission price variations for large CRNP customers exacerbated by large price increases that are occurring at the same time across all customers due to increasing transmission and distribution costs.

We are concerned that dramatic changes to the framework may cause even greater transmission charge variability and uncertainty. EnergyAustralia supports efforts to improve economic efficiency in the transmission network. However it is critically important that any proposed changes to the transmission pricing arrangements take into account any potential impacts for price volatility and price path uncertainty to transmission network users and their end-customers.

However there may also be opportunity to improve outcomes for customers by identifying changes to processes and methodologies which improve pricing arrangements from transmission to distribution to retailer. For example there are likely to be economic and equity benefits to be realised if the transmission framework provided for increased transparency in the TNSP pricing process and for transmission companies to publish their pricing strategy.

2 Response to questions posed in AEMC Issues Paper

2.1 Question 1

Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?

We have already noted in our general comments that most key aspects of the frameworks governing transmission investment have only been in place since late 2006 following considerable review by the Commission and stakeholders and there are significant rule changes that are currently in progress or have recently come into place (such as the creation of the role of National Transmission Planner and the new Regulatory Investment Test for Transmission (RIT-T)).

We are not aware of any evidence that would suggest that the existing frameworks do not promote efficient outcomes consistent with the NEO. However, with the recent changes to the frameworks, that will have large impacts on the planning of the transmission network, it is too early at this stage to determine what the impact of these changes will be and what further changes will be needed.

We therefore do not support another wide ranging review of the economic framework for transmission investment. This would only serve to undo the basis of the previous framework review – that is to create an environment of investment certainty for all stakeholders.

If any review is necessary, it is a review of the rules architecture to ensure it delivers consistent outcomes. We see benefit particularly in a considered review of the operation of the Rules in terms of service definition and charges to customers. Recent reviews (SENE) and Rule changes (United Energy Rule change on TUoS recovery) suggest there is some ambiguity in how the Rules operate in respect of the interaction of assets and services delivered by TNSPs and the process for passing through the costs of these assets and services to customers.

In this regard, we do observe that the existing framework provides limited cost signals to generators regarding the location decisions in respect of the shared network. Whilst generators pay the dedicated connection costs, the deeper network augmentation costs are paid by all network users. Locational price signals for generators are therefore more focused towards the generators' ability to dispatch energy rather than any costs associated with the location of the generator in relation to the shared transmission network, because they are not subject to the transportation costs.

We also make the observation that transmission pricing arrangements differ to those for distribution businesses. Transmission pricing arrangements focus on allocation of revenue and costs, whereas the distribution pricing rules have a strong economic focus of avoidable costs, standalone and long-run marginal costs.

Efficient joint planning can result in considerable efficiencies in network investment. The integration of replacement and capacity planning is particularly important in this regard. It should be noted that a number of joint planning models exist, and operate with different levels of effectiveness. This review does not consider that there may be an issue in this regard.

2.2 Question 2

Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?

Consideration needs to be given to whether the suggested role of transmission network service providers is specified correctly and at the correct level. We would caution against an approach that transitioned services provided by transmission businesses to the competitive market.

Traditionally transmission businesses enable energy to be transported from generators to distribution networks (through to end users) to meet minimum service levels at least cost (or maximum benefit)[2]. If, as proposed, Transmission Network Service Providers (TNSPs) were required to manage risks associated with generator congestion, this changes the dynamic of the traditional transmission role completely. This would expose the regulated entity to risk that may no longer be kept to a tolerable level, for events beyond the TNSP's control. We question how the traditional role can be sustained whilst also requiring TNSPs to be financially responsible for commercial services. It is also unclear how a "different" service can be applied to any one "customer" though the conveyance of electricity across a shared network. We provide further comment on this issue in response to question 7.

In any case, most of the flow of energy through transmission networks occurs over shared assets. These assets provide services to all participants, however the cost of network use is born by customers rather than generators. Unless unconstrained development of the network is allowed, (which would be highly inefficient) it is inevitable that the network will at times be constrained either as a result of inherent congestion or outages. It would not be possible to develop an efficient network, which was not constrained at some time. The principles of providing compensation where it is not economically efficient to address constraints must be questioned.

Quite apart from determining the issue of accountability for compensating constrained loads, any compensation for a constraint is effectively a wealth transfer within the NEM. Ultimately, the costs of compensation must be recovered from either customers or the market in some way. Care would need to be taken that any contemplated mechanism is not a default subsidy.

We also question the premise that generators should have a greater access to compensation than load customers, including both directly connected customers and those supplied by Distribution Network Service Provider networks.

<u>The role of DNSPs in relation to TNSPs</u>

Whilst not specifically in answer to this question, we raise the comment that the issues paper omits any reference to DNSPs and in particular;

- the existing service provided by TNSPs to customers including DNSPs, and
- the role of DNSPs as the network services providers between transmission networks and load.

TNSPs provide service to DNSPs in;

- preventing very wide area interruptions to DNSP customers, and
- keeping their transmission system intact and not exposing DNSPs to an excessive risk of interruption.

There is no discussion of the appropriate level of service or the relative efficiency of such services.

Assuming the reference to load customers in the issues paper is broader than customers connected directly to the transmission network, the omission of DNPSs in this vision neglects to consider the role of DNSPs as the immediate recipient of TNSP services, the actual customers of DNSP responsible for payment of transmission related charges and, in particular, the role of DNSPs in passing through transmission related charges to load customers.

[2] Note: Whilst to date demand side response (from distributors and end users) has not provided significant contribution, the may become an additional consideration in the role of transmission.

The flow-on impact of TNSP changes in DNSP networks

The other important issue with respect to DNSPs is the extent to which any changes or even fine tuning to existing networks may impact upon DNSPs and that to the extent that any consequential changes might need to be made the DNSP frameworks, the potential consequences should be considered as part of this review.

The Commission acknowledges[3] that the transmission frameworks are complex and inter-related and that it will be necessary to develop internally consistent packages of reforms. EnergyAustralia strongly submits that the Commission's consideration must extend to the impacts for distribution and that it is not satisfactory for changes to DNSP frameworks to be considered separately. Past experience has shown that decisions made in transmission do to a large degree pre-empt the approach taken in distribution, the proposed application of the SENE concept to distribution provides an example of this as does the application of the negotiated service framework in Chapter 6.

2.3 Question 3

Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market based signals might be beneficial?

We reiterate earlier comments that the impact of recent changes will take time to assess. For TNSPs to forecast future needs they must base their decisions on both information available and the timeframes that they are imposed as a result of the planning (regulatory) framework. TNSPs rely on connecting participants to provide information as early as possible in their planning process. However, transparency of information in the market place can be inhibited due to confidentiality/commercial concerns.

We do see some benefit in TNSPs incorporating DNSP information on customer service issues in the planning and design of the transmission network. We also note that the incentives for transmission businesses in the existing frameworks are (primarily) market driven. There may also be benefit in focusing on impacts to end customers. For example, there would be benefits to end customers by ensuring the reliability standards for transmission and distribution businesses work together to deliver customer outcomes.

2.4 Question 4

Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?

Considering the new RIT-T has only just been introduced it is difficult to provide a definite response. The RIT-T presents a change from existing requirements and it would be expected it will take some time to assess its impact. It should be noted that adherence to the RIT-T requires significant analysis of options in a variety of scenarios. It is considered that the complexity of the requirements will not facilitate timely investments in the shared network, which will result in inefficiencies.

We also note that a number of other aspects of the transmission framework have only been in place for a relatively short time and there are significant rule changes that are currently in progress. Evidence on the success of these initiatives will not be available in the timeframes for this review (findings and recommendations to the MCE by November 2011).

[3] August 2010 AEMC Issues Paper Transmission Frameworks Review, p iv

2.5 Question 5

Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?

As previously commented, the current framework has only been in place since the end of 2006, not yet five years and therefore has not really been time for this to be assessed over a reasonable timeframe.

We do note that the present regulatory process is targeted towards ensuring that the regulatory determination only funds efficient investment and reviews are targeted at reducing expenditure. Whilst submissions by transmission businesses as part of the regulatory proposal process consider a range of development scenarios, inevitably development requirements will vary from those used in the submission process.

The present framework is advantageous in that it promotes transparency in providing a codified approach to decision-making. The framework also promotes investor certainty and eliminates “after the fact” optimisation of investments made during the period. We also observe that the framework provides a financial incentive for TNSPs to under spend their determination. This provides a financial disincentive for TNSPs invest in projects that may have been not identified at the time of the submission, or dismissed during the determination process. Problems may occur where the regulator reduces expenditure forecasts below what is necessary to maintain a safe, secure and reliable network. Under these circumstances TNSPs will be incentivised to prioritise their investment portfolio, which may not necessarily provide for efficient market outcomes.

In addition the existing transmission framework provides for the AER's determination to recognise contingent projects. These are projects which have been identified at the time of the regulatory proposal but which cannot be forecast with sufficient certainty to warrant inclusion in the expenditure forecasts. If these contingent projects are triggered during the regulatory control period, there is a process for amending the revenue arrangements to reflect the required expenditure.

2.6 Question 6

Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?

We believe that there are potential economic efficiency benefits to be realised from pricing arrangements that better reflect the economic costs imposed by load and generation. There may also be potential for improvement in economic welfare from reforming transmission prices, which are currently based largely on cost allocation principles, rather than economic principles. While EnergyAustralia recognises that cost allocation principles have an important role to play in achieving equitable allocation of common network costs to network users, the pricing outcomes produced by this approach can often provide users with unclear signals of the marginal cost of their transmission network use or location decisions.

This problem is particularly an issue for large customers who receive a cost reflective network price and is exacerbated under a revenue cap arrangement where transmission prices can easily deviate from underlying economic costs due to the under/over recovery mechanism. In such a scenario, it is conceivable that these customers may respond to the transmission pricing signal only to find it has little bearing on the total charge they pay for the use of the transmission network in future periods.

By way of example, suppose a large industrial customer on a cost reflective network (distribution and transmission) tariff, in response to the signal provided by the TUOS component of the tariff (demand/peak pricing), makes rational consumption and investment decisions concerning its use of the transmission network. To the extent that the TNSP transmission price signal does not appropriately reflect the economic (forward-looking) cost associated with the use of the transmission network, the customer’s decisions about avoiding the peak period of the network, while rational, are unlikely in this situation to be optimal from an economic perspective and, in fact, may even have no impact on the transmission costs borne by the customer.

In addition, suppose that the industrial customer responds to the introduction of efficient price signals by dramatically reducing peak demand. While this behaviour will flow through to lower transmission network costs in the long-run, the reduction in TNSP revenue in the current period under the revenue cap will flow through to higher prices in the next period. This situation may result in equity concerns if the TNSP sets its prices to recover this shortfall from other customers or may even undermine economic efficiency if this shortfall is recovered from the industrial customer in the form of higher fixed charges.

There is an important caveat to our comments regarding pricing arrangements. While EnergyAustralia supports efforts to improve economic efficiency in the transmission network, it is critically important that any changes to the transmission pricing arrangements do not create unacceptable price volatility and/or price path uncertainty to transmission network users and their end-customers. As a distribution business, EnergyAustralia is committed to preserving the Transmission price signal where it is economically desirable to do so (i.e. for large customers on an individually calculated network tariff). Given that large customers are typically connected to the higher voltage level of the distribution network, the transmission component accounts for a significant share of their network bill. Therefore, any changes in the structure and level of transmission charges have the potential to translate to significant network price volatility for these customers. Unexpected price volatility not only raises equity concerns, but also undermines economic welfare as these customers often make significant investment decisions based on their expectations of future network price movements.

Furthermore, we consider that there are likely to be economic and equity benefits to be realised from requiring transmission businesses to:

- Publish a medium-term pricing strategy document, explain any departures from this strategic direction, and undertake consultation with external stakeholders impacted by these reforms.
- Improve transparency with their transmission price modelling process and to explain any year-on-year changes to the assumptions, inputs and cost allocation process on both economic and equity grounds. This will ensure that all year-on-year changes have been identified and explained to external stakeholders.

2.7 Question 7

Would it be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service? Would this help generators to manage risks around constraints and dispatch uncertainty?

We reiterate our earlier comments that there is benefit in considering the potential economic efficiency benefits that may be realised from pricing arrangements that better reflect the economic costs which both load and generation imposes. However we do not agree with the concept of placing requirements on TNSPs to separately provide unique service provision using shared infrastructure.

We acknowledge that allocation of long term capacity is a complex issue. The service provided by transmission networks generally comprises shared assets. Transmission can neither control the despatch or development of generators. It is unreasonable and physically impractical to require that a TNSP would guarantee priority access or service to one party over shared assets as it would potentially restrict access to another user (competitor) and thereby circumvent the principles of the market. To practically provide an "enhanced level of transmission service" would mean that the network would need to accept (or supply) power under a wider range of normal and abnormal network conditions. Whilst for dedicated connection assets this is possible (as is the case today) it is difficult to understand how this could be practicality achieved for shared assets:

- For Dedicated Connecting Assets - Loads and customers already have an option to incorporate enhanced redundancy in the connecting assets should they chose to do so. For example they can choose to pay for whatever level of redundancy they may deem appropriate for these assets (noting that normally they stop at N-1 because the upstream network can generally only provide N-1).
- Shared Upstream Assets - Offering enhanced capacity or redundancy could become problematic in the sense that this would involve an "ongoing contracted" arrangement. This is due to the reality of dynamic networks and arrangements that change continually over time. This would have the effect of gradually eroding the enhanced service that the load/generators presumably paid for at the outset. Accordingly, ongoing investment may be required from the load/generator to maintain the level of enhancement requested. The mechanisms for obtaining a contribution for the costs of maintaining the enhanced service over time are likely to become difficult, especially where these shared assets are utilised by more than one load/generator having requested an enhanced service. This would be an even deeper level of complexity and fertile ground for dispute and ambit claims to protect rights and or discourage competition.

EnergyAustralia believes that a complex system of negotiated access rights in every instance would be problematic and unwarranted. The current type and range of regulatory incentives on NSPs have been demonstrated to provide appropriate behaviours by NSPs.

This is not to say that customers have no flexibility to enhance the service they believe they need. However specific service arrangements should be limited to dedicated asset infrastructure that can be negotiated separately. Where a customer wishes to enhance the shared network (build out a constraint for instance), there should be the availability to fund the augmentation on the acknowledgement that a shared network cannot physically cater for exclusive use of the shared network element.

2.8 Question 8

Do current arrangements for the connection of generators and large end-users reflect the needs of the market? To the extent that more fundamental reforms to transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

We reiterate our comments about our reluctance to move toward more fundamental changes to the transmission framework, beyond clarification of service delivery and pricing arrangements.

Clause 5.3 of the Rules is intended to provide the customer (and the network) with a clear understanding of the specifics of a connection. Unfortunately this is never the case and ongoing iterative consultation and constructive dialogue over an ongoing period of time is required to settle and finalise the connection arrangement.

The existing arrangements do not necessarily exclude this ongoing consultation. However they are not structured in a way that recognises how fundamental and critical this is to the process. We propose that a more "grounded" framework is needed that recognises the natural partnership required between NSP and proponent in jointly developing details for both sides of the connection.

In particular for generators, an economic solution will generally be a compromise between what the proponent would like to connect and what the NSP can readily connect. The existing rules do not really promote the inherent flexibility between NSP and proponent to work toward finding the economic "sweet spot" for these sorts of projects.

We note the issues paper is scant in its reference to the nature of the service provided by TNSPs to DNSPs. We believe there is some room for improvement here. Whilst the incentives for transmission businesses in the existing frameworks are (primarily) market driven we consider that there is a cost associated with not providing some focus (with associated metrics) to the impacts on end customers. For this reason, we consider that there would be benefits for the reliability standards for transmission and distribution businesses to work together to deliver customer outcomes. For example; a distribution business could invest in the network to deliver N-2 reliability standards in a CBD area however without a corresponding investment in the upstream transmission network there outcomes will not be delivered to the customers.

The DNSP is a proxy of the majority of end use customers and as such require certain standards of reliability of supply from the TNSPs. The current transmission reliability measures do not record/measure or provide the ability to plan for a level of risk of continuity of supply at the TNSP supply point to DNSPs. Transmission Reliability standards should be outcome based and focussed toward the level of service provided at the connection point.

The Review gives little consideration of the deep impacts of connection. In particular how costs associated with controlling fault levels should be allocated or how the at times scarce fault level capacity should be allocated between competing interests.

2.9 Question 9

Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?

We reiterate our comments about our reluctance to move toward more fundamental changes to the transmission framework, beyond clarification of service delivery and pricing arrangements. We also refer the AEMC to our response to question 5 regarding the existing economic framework.

We therefore believe that changes, if any, are more likely to be incremental rather than fundamental. To this end we note our previous comments (made in response to question 8) regarding the need to take into account the end-user on a distribution network. While there is emphasis on ensuring market outcomes are maximised, there is also a need to ensure end user reliability outcomes are maintained.

2.10 Question 10

Is there a need for material congestion to be more efficiently managed in the NEM?

We refer to our comment in response to question 2, but otherwise offer no further comments on this issue.